IIEC Exhibit 2

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER COMPANY :
:
Proposed revisions to delivery service : Docket No. 01-0432
tariff sheets and other sheets :

Direct Testimony of

Michael Gorman

On behalf of

Illinois Industrial Energy Consumers

September 2001
Project 7626

BRUBAKER & ASSOCIATES, INC.
ST. LOUIS, MO 63141-2000

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

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Direct Testimony of Michael Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael Gorman; my business address is 1215 Fern Ridge Parkway, Suite 208; St. Louis, MO 63141-2000.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation with Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A These are set forth in Appendix A of my testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am appearing on behalf of the Illinois Industrial Energy Consumers (IIEC). The IIEC is an ad hoc group of industrial customers eligible to take delivery service from Illinois Power Company (Company or IP).

Q PLEASE SUMMARIZE YOUR TESTIMONY.

A I recommend a return on common equity for IP of 11.1%. I also describe the general sentiment of a distribution utility's risk expressed by security analysts, utility executives and regulatory commissions.

Q PLEASE SUMMARIZE THE REVENUE REQUIREMENT IMPACT ASSOCIATED WITH IIEC WITNESSES' RECOMMENDED ADJUSTMENTS.

A Table 1 below describes the recommendations or adjustments being made by either myself or Mr. Nicholas Phillips and the associated revenue impact

TABLE 1

Revenue Requirement Impact
($ Millions)

Description	Amount
Reduce ROE to 11.1%	$ 7.9
A&G Expense	30.3
General and Intangible Plant	15.0
Total	$53.2

I am sponsoring the adjustment to the Company's proposed return on common equity, and IIEC witness Phillips, is sponsoring IIEC's adjustments to the Company's A&G expenses and general and intangible plant.

Q HOW WILL YOUR TESTIMONY BE ORGANIZED FROM THIS POINT FORWARD?

A I will first describe my justification for an 11.1% return on common equity, and respond to IP witness Dr. Paul R. Moul's support for IP's requested equity return of 12.5%.

Distribution Utility Risk

Q IN YOUR ANALYSIS OF AN APPROPRIATE RETURN ON COMMON EQUITY FOR IP, DO YOU NEED TO ASSESS ITS RISK?

A Yes. It is important at this juncture to distinguish between IP's going-forward risk as a distribution utility, in relationship to the risk of its past operations as an integrated electric utility. As discussed below, the general consensus of credit and equity analysts is that the risk profiles for distribution utilities are different from those of integrated electric companies, or companies which provide generation-only services. In fact, it is important to note, since at this time IP's going-forward operations will be dedicated entirely to Transmission (T) and Distribution (D) services, that the risk for the T&D functions is lower than that of an integrated electric and a generation-only company. Hence, it is appropriate to reflect this lower risk in IP's overall rate of return. Its risk reduction should be reflected in either its capital structure through an appropriate mix of debt and equity, or its return on equity.

Q CAN YOU PLEASE DISTINGUISH BETWEEN THE RISK OF AN ELECTRIC DISTRIBUTION UTILITY AND AN INTEGRATED ELECTRIC COMPANY?

A It appears to be the general industry consensus that a distribution utility has lower risk than an integrated electric utility and generation-only electric company. A distribution utility is generally regarded to have lower risk because it will remain a regulated utility, and will therefore continue to earn predictable earnings and cash flows.

Q PLEASE DESCRIBE THE SUPPORT YOU HAVE FOR YOUR UNDERSTANDING OF THE RISK OF A DISTRIBUTION UTILITY IN RELATION TO AN INTEGRATED ELECTRIC AND GENERATION COMPANY.

A My position concerning the risk of a distribution utility is supported by reports from credit rating agencies and equity security analysts, and statements of utility executives.

Q PLEASE SUMMARIZE THE LITERATURE DESCRIBING CREDIT RATING AGENCIES' POSITIONS ON THE RISK OF A DISTRIBUTION UTILITY.

A Bond rating agencies have consistently taken the position that the business risk of T&D utilities is considerably lower than that of an integrated electric and generation only electric company. Following are some examples of opinions published by credit rating agencies.

Standard & Poor's stated as follows:

> "Owing to the relatively low business risk of large transmission systems and regulated distribution systems (the "wires" business), business profile assessments in this area should fall within the 1-4 range. The generation business is the most risky, reflecting the competitive nature of the business, and generators generally receive business profile assessments in the 7-10 range." (Standard & Poor's rates business risk on a scale of 1 (lowest risk) to 10 (highest risk). Global Utilities Rating Service, Industry Commentary, Rating Methodology for Global Power Companies, Standard & Poor's, May 1997.)

Fitch IBCA commented as follows:

> "Electric distribution is widely viewed as a low-risk industry, especially when it is carried out pursuant to an exclusive monopoly franchise. However, several credit concerns exist for electric distribution utilities, including. . ." [regulatory risk, commodity price/market risk, obsolescence and technology risk, mergers and acquisition]. (Global Power/Electric Special Report, Electric Distribution Credit Criteria, Fitch IBCA, October 7, 1999, at 62.)

Moody's Investors Service, based on its experience with distribution utilities in the United Kingdom, Australia and Chile, concluded as follows:

> "• In general, distribution companies, regardless of their business profiles, exhibit lower business risk than generation companies as they are less asset-intensive and will remain regulated to a large degree.
>
> • 'Pure' and largely regulated distribution companies–that is, those with virtually no exposure to generation or other highly competitive and volatile energy-related business–can tolerate significantly lower interest or fixed charge coverage and higher leverage ratios than traditional US investor-owned utilities (IOUs) and still achieve the same ratings." (Future Electric Distributors: More Stable Than Generators, But Not Risk Free, Moody's Investors Service, October 1997)

Finally, Duff and Phelps stated as follows:

> "Even with a relatively wide diversity of risk profiles within the electric distribution industry we believe most companies that stayed mainly in the electric distribution business will present very low risk profiles when compared to almost all other industries." (Rating Methodology, DCR's Approach to Rating Electric Distribution Companies, October 1999, at 6.)

Q PLEASE DESCRIBE YOUR FINDINGS CONCERNING EQUITY SECURITY ANALYSTS' POSITIONS ON THE RELATIVE RISK OF A DISTRIBUTION UTILITY.

A In its electric utility industry summary, the Value Line Investment Survey stated the following:

> "Electric generation is being deregulated in many states who are prodding utilities to divest these assets or move them into non-regulated divisions. Generation companies will be riskier, but offer higher returns. Transmission and distribution companies, which will

> stay regulated, should produce the steady earnings and dividend stream favored by traditional utility investors." (The Value Line Investment Survey, March 12, 1999, at 159)

Q PLEASE DESCRIBE YOUR EVIDENCE CONCERNING DISTRIBUTION UTILITY EXECUTIVES' OPINIONS OF RISK CONCERNING DISTRIBUTION UTILITIES.

A In the Application of Virginia Electric & Power Company for approval of a functional separation plan, Mr. James P. Carney, the Assistant Treasurer of Dominion Resources and Virginia Electric & Power Company, offered his company's risk opinion to the Corporation Commission of Virginia in Case No. PUE 000584, in testimony filed on May 1, 2001. The purpose of his testimony was to describe the company's plan for legal separation and approval of a functional separation plan of its transmission and distribution businesses, and the company's then unregulated generation business. Concerning the relative risk of the T&D business in relation to the unregulated generation business, Mr. Carney testified as follows:

> "The Company has recently received rating guidance on its legal separation scenario from both Moody's Investors Service and Standard & Poor's. As part of those discussions, it was confirmed that the integrated entity would be riskier than the T&D company by itself, but less risky than a generation company on a stand-alone basis." (Direct Testimony, at 9)

He went on to describe rating agencies' reports in his analysis to support the conclusion that the cost of debt would be less for a T&D business than it would be for an integrated electric utility, or a generation business, even at the same bond rating (id. at 10).

In the same filing, Virginia Electric & Power Company also sponsored testimony from Jonathan E. Baliff who was then Vice-President of Credit Suisse First Boston (CSFB). The purpose of Mr. Baliff's testimony was to describe the current financial markets perspective regarding legal separation of generation and transmission and distribution business from the vertically integrated utility, in the United States. Mr. Baliff testified as follows:

> "In an era of retail choice, the risk profile of a generation and T&D business is different. Generation is a competitive, less regulated, more risky business than T&D. There are five general risk factors attributable to competitive generation business: commodity or output risk, fuel supply, technology, operational, and regulatory risk. Commodity or generation output risk concerns the price of electricity, and is primarily a function of the wholesale market characteristics or, in the case of contracted power, the specific design of the power purchase agreement and off taker credit quality. Fuel supply is a function of a generator's ability to match commodity and transportation costs with output revenue to sustain profit margins. Technology and operations risks concern the ability of a generator's assets to physically produce electricity within their design specifications, and to realize costs within ranges necessary to sustain a profit margin. Finally, regulatory risk exists with regard to federal, state and local laws, especially concerning environmental regulations. T&D businesses, though insulated monopolies with significant oversight from the state and federal commissions, still face some risks including the obvious regulatory risks, electric supply, overall demographic/ economic and operations risks. Regulatory and electric supply risks are by far the most significant. The risks are inter-related through retail choice transition plans, especially if the T&D businesses are the default supply provider. T&D businesses are also exposed to general downturns in the economic/demographic environment. Operation risks, though slight, are also a factor." (id. at 2 and 3)

Mr. Baliff also goes on to describe the Standard & Poor's and Moody's reports cited above in support of his contention that T&D businesses have lower risks than either an integrated electric utility, or a generation stand-alone company.

Q HAVE OTHER UTILITY EXECUTIVES OFFERED SIMILAR TESTIMONY CORROBORATING THAT A T&D RISK IS LOWER THAN THAT OF AN INTEGRATED ELECTRIC UTILITY OR A GENERATION STAND-ALONE COMPANY?

A Yes. In rate filings by Duquesne Light Company, subsidiary of DQE, Inc., the utility took the position that its capital structure should be adjusted to reflect the sale of its generating assets in the generation business. DQE's capital structure, which had been used as a proxy for its integrated utility affiliate's capital structure, was then adjusted to reflect the wires-only electric company. The company argued this was a reasonable proxy for a capital structure for a water and sewer distribution company. Testimony in support for these positions was offered by James A. Lahtinen, Vice President, Rates and Regulatory Affairs, DQE, Inc. (Application of AquaSource Utility to Change Rates, SOAH Docket No. 582-01-0416, TNRCC Docket Nos. 2000-1074-UCR & 2000-1075-UCR, May 25, 2001, Attachment 36, at 9)

Similarly, a Vice President and Treasurer of Texas New Mexico Power Company (TNP) offered testimony in TNP's bundled cost of service filing concerning an appropriate capital structure for a T&D utility:

> "Historically, a reasonable capital structure for an integrated utility with an investment grade bond rating has been in the range of 50-55% debt. The debt ratio above this level subjected the integrated utility to the risk of having a below investment grade bond rating. However, as the generating assets are separated from those of the T&D, and the resulting T&D entity remains a regulated monopoly, some amount of additional leverage may be allowed while still maintaining an investment grade bond rating. TNP believes that a 60% debt ratio will be appropriate for the regulated T&D businesses and still allow TNP's bonds to maintain their investment grade bond rating. Since debt is a less expensive form of financing than equity, this higher leverage should result in lower cost to TNP's customers." (Unbundled Cost of Service by Texas-New Mexico Power Company, Testimony of Patrick L. Bridges, March 31, 2000, at 6-7, SOAH Docket No. 473-00-1014, PUC Docket No. 22349.)

Q WHAT CONCLUSIONS CAN BE DRAWN FROM THE CREDIT RATING AND UTILITY EXECUTIVES' POSITIONS CONCERNING THE RISK OF A

DISTRIBUTION UTILITY IN COMPARISON TO AN INTEGRATED ELECTRIC UTILITY?

A The conclusions are clear -- a distribution utility's business risk is lower than that of an integrated electric utility, or a generation-only utility. Based on their expectations of lower business risk, credit analysts and utility executives have concluded that it is reasonable to finance a distribution utility with greater amounts of debt that, in turn, increases the financial risk of a distribution utility compared to an integrated electric utility. This greater financial risk is made possible, while preserving the bond rating, because the business risk of a distribution utility is lower than that of an integrated electric utility or a generation-only company. This lower business risk allows the distribution utility to lower its cost of capital in financing its distribution assets by increasing its use of debt compared to an integrated electric utility.

Q PLEASE DESCRIBE THE POSITIONS TAKEN BY OTHER REGULATORY AGENCIES CONCERNING THE RELATIVE RISK OF A DISTRIBUTION UTILITY.

A The Public Utility Commission of Texas considered the appropriate capital structure for the transmission and distribution utilities that operate in the state of Texas. In the Texas restructuring law, transmission and distribution utilities will be separated from the integrated electric companies, and will provide only transmission and distribution services.

The Commission found, based on a careful consideration of the remaining business structure, after complete separation of generation, transmission and distribution functions, and the makeup of the Texas retail market that the distribution utilities in Texas exhibited lower risk than that of an integrated utility. To reflect this risk in the ratemaking process, the Commission found an appropriate capital structure for a distribution utility to be 60% debt and 40% common equity." (Generic Issues Associated with Application for Approval of Unbundled Cost of Service Rate, Public Utility Commission of Texas, Docket No. 22344, Order No. 42, Interim Order Establishing Return on Equity and Capital Structure, December 18, 2000)

In a separate finding, the Montana Public Service Commission considered an appropriate capital structure for a distribution only company to be composed of a 43% common equity ratio. The commission also rejected adjustments to the DCF and CAPM model results proposed by the Company in that case, which are similar to those being proposed by IP witness Moul in this proceeding. Also, like the Texas Commission, the Montana Commission concurred with bond rating agencies that a distribution utility's risk is lower than that of an integrated utility. The Montana Commission stated:

> ". . .The Commission concurs with the Large Customer Group and comments by Standard & Poor's that the sale of the generation facilities enhanced MPC's business risk profile and credit profile." (In the Matter of Application of the Montana Power Company for Authority to Increase Rates for Electric and Gas Service, Department of Public Service Regulation, Before the Public Service Commission of the State of Montana, Docket No. D 2000.8.113, Final Order No. 6271C, May 9, 2001, at 8 and 19)

Q WHAT CONCLUSIONS CAN BE DRAWN FROM ORDERS OF OTHER REGULATORY COMMISSIONS?

A The conclusion is clear. Other regulatory commissions that have reviewed the issues of the risk of T&D utilities, compared to an integrated electric utility, and a generation-only company, have concluded a T&D electric utility's risk is lower. Based on this lower risk, these commissions found that the utilities should finance their distribution assets with a greater percentage of debt and lower percentages of common equity. The effect of adjusting the capital structure to include more debt reduces the overall rate of return for a distribution utility.

Capital Structure and Cost of Long-Term Debt and Preferred Stock

Q IS IP'S PROPOSED CAPITAL STRUCTURE IN THIS PROCEEDING REASONABLE FOR SETTING A DISTRIBUTION UTILITY'S RATES?

A Yes. Excluding its transition bonds, the ratio of IP's common equity to total utility capital is 45.4% (Revised IP Ex. 3.2). The common equity ratio of 45.4% is reasonable for a distribution utility.

Q HAVE BOND RATING AGENCIES OFFERED AN OPINION ON APPROPRIATE CAPITAL STRUCTURE FOR A DISTRIBUTION UTILITY?

A Yes. Standard & Poor's and Fitch IBCA both are projecting transmission and distribution utilities to contain the median debt to total capital ratio of approximately 55%. Hence, IP's total debt ratio as a percentage of total utility capital of approximately 49.1% is somewhat low in comparison to the S&P and Fitch projection for a distribution utility. However, this low amount of debt is somewhat offset by the approximately 5.5% preferred stock weighting of total capital. On balance, IP's utility capital represents a reasonable mix of debt and common equity for a distribution utility.

Q DOES IP'S CAPITAL STRUCTURE REFLECT THE LOWER BUSINESS RISK OF A DISTRIBUTION UTILITY?

A Yes. As discussed above, IP's common equity ratio and its balance of long-term debt and preferred equity, reflect a reasonable balanced capital structure for a distribution utility. Hence, the mix of debt and equity in this capital structure reflects a higher percentage of debt, which is justified by the lower business risk related to distribution utility operations as compared to an integrated electric utility. Therefore, I will not propose an adjustment to IP's return on common equity, as measured below, to reflect IP's reduced business risk.

Q DO YOU TAKE ISSUE WITH THE COST OF LONG-TERM DEBT, SHORT-TERM DEBT, AND PREFERRED STOCK SECURITIES ESTIMATED BY IP WITNESS DANIEL MORTLAND?

A No.

Return on Common Equity

Q WHAT IS YOUR RECOMMENDATION?

A I recommend IP be authorized a return on common equity of 11.1%.

Q PLEASE DESCRIBE THE FRAMEWORK FOR DETERMINING A REGULATED COMPANY'S COST OF COMMON EQUITY.

A In general, determining a fair cost of common equity for a regulated utility has been framed by two decisions of the U.S. Supreme Court, in Bluefield Water Works vs West Virginia PSC (1923) and Federal Power Commission vs Hope Natural Gas Company (1944).

These decisions identify the general standards to be considered in establishing the cost of common equity for a public utility. Those general standards are that the authorized return should: (1) be sufficient to maintain financial integrity, (2) attract capital under reasonable terms, and (3) be commensurate with returns investors could earn by investing in other enterprises of comparable risk.

Q PLEASE DESCRIBE WHAT IS MEANT BY THE TERM "UTILITY'S COST OF COMMON EQUITY."

A The utility's cost of common equity is the return investors expect, or require, in order to make an investment. Investors expect to achieve their return requirement from receiving dividends and stock price appreciation.

Q PLEASE DESCRIBE THE METHODS YOU HAVE USED TO ESTIMATE THE COST OF COMMON EQUITY FOR IP.

A I have used several models based on financial theory to estimate IP's cost of common equity. These models are: (1) the constant growth discounted cash flow (DCF) model, (2) the non-constant growth DCF model, (3) the bond yield plus equity risk premium model and (4) a capital asset pricing model (CAPM). I have applied these models to a group of publicly traded utilities that I have determined to represent the investment risk of an electric utility similar to IP.

Q HOW WILL YOU DEVELOP A DISCOUNTED CASH FLOW ANALYSIS AND RISK PREMIUM ESTIMATES FOR IP?

A I relied on a broad based group of electric utility companies in which to estimate IP's return on equity.

Q HOW DID YOU SELECT A BROAD BASED GROUP OF ELECTRIC UTILITY COMPANIES?

A I started with all the electric and combination electric and gas utilities followed by the C.A. Turner Utility Reports. I limited the comparable group to the utilities which met the following criteria: (a) had at least 80% of their revenues form the provision of electric utility service; and (b) had investment grade bond rating from both Standard & Poor's and Moody's. The bond ratings, after the credit analysts' assessments of the company's total investment risk, included both business risk and financial risk. Hence, a bond rating is a reasonable proxy for the total investment risk of an electric utility.

As shown on my IIEC Exhibit 2, Schedule 1, this selection criteria produced a broad-based group of electric utilities from which to estimate a fair return for IP.

Discounted Cash Flow (DCF) Model

Q PLEASE DESCRIBE THE DCF MODEL.

A The DCF model posits that a stock price is valued by summing the present value of expected future cash flows discounted at the investor's required rate of return (ROR) or cost of capital. This model is expressed mathematically as follows:

$$P_0 = \frac{D_1}{(1+K)^1} + \frac{D_2}{(1+K)^2} \; .\,.\,.\,. \; \frac{D_4}{(1+K)^4} \quad \text{where} \qquad \text{(Equation 1)}$$

P_0= Current stock price
D = Dividends in periods 1 - 4
K = Investor's required return

This model can be rearranged in order to estimate the discount rate or investor required return, "K." If it is reasonable to assume that earnings and dividends will grow at a constant rate, then Equation 1 can be rearranged as follows:

$$K = D_1/P_0 + G \qquad \text{(Equation 2)}$$

K = Investor's required return
D_1 = Dividend adjusted for growth
P_0 = Current stock price
G = Expected constant dividend growth rate

Equation 2 is referred to as the "constant growth" annual DCF model.

Constant Growth DCF Model

Q PLEASE DESCRIBE THE INPUTS TO YOUR CONSTANT GROWTH DCF MODEL.

A As shown under Equation 2 above, the DCF model requires a current stock price, expected dividend, and expected growth rate in dividends.

Q WHAT STOCK PRICE AND DIVIDEND HAVE YOU RELIED ON IN YOUR CONSTANT GROWTH DCF MODEL?

A I relied on the average of the weekly high and low stock prices over a 13-week period ending August 6, 2001. An average stock price is less susceptible to market price variations than is a spot price. Therefore, an average stock price is less susceptible to aberrant market price movements, which may not be reflective of the stock's long-term value.

I used the most recently paid quarterly dividend, as reported in the Value Line Investment Survey. This dividend was annualized (multiplied by 4) and adjusted for next year's growth to produce the D_1 factor for use in Equation 2 above.

Q WHAT DIVIDEND GROWTH RATES HAVE YOU USED IN YOUR DCF MODEL?

A There are several methods which one can use in order to estimate the expected growth in dividends. However, for purposes of determining the market required return on common equity, one must attempt to estimate what the consensus of investors believe the dividend or earnings growth rate will be, and not what an individual investor or analyst may use to form individual investment decisions.

Security analyst growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data.[1] Because they are more reliable estimates, and assuming the market, in general, makes rational investment decisions, analysts' growth projections are the most likely growth estimates that are built into stock prices.

For my constant growth DCF analysis, I have relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for the investor consensus dividend growth rate expectations. My growth estimates were taken from Institutional Brokers Estimate System (IBES) on August 17, 2001. IBES surveys security analysts and publishes a simple arithmetic average or mean of surveyed analysts' earnings growth forecast. A simple average of the IBES growth forecast gives equal weight to all surveyed analysts' projections. It is problematic as to whether any particular analyst's forecast is most representative of general market expectations. Therefore, a simple average, or arithmetic mean, analyst forecast is a good proxy for market consensus expectations.

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[1] See, for example, David Gordon, Myron Gordon, and Lawrence Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989.

Q **DID YOU PERFORM AN ANNUAL DCF MODEL OR A QUARTERLY DCF MODEL TO SUPPORT YOUR RECOMMENDATIONS IN THIS PROCEEDING?**

A I relied upon a quarterly DCF model, because that is the model traditionally accepted by the Illinois Commerce Commission. However, I believe the quarterly DCF model produces a higher result because it first states the dividend reinvestment return of investors. The quarterly DCF model will allow investors to earn the dividend reinvestment return twice: first, through the authorized return on common equity, and a second time as dividends are actually paid and reinvested. Hence, the quarterly DCF model is, in my judgment, inferior to the annual DCF model for estimating a rate of return to use in a ratemaking proceeding.

Q **WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF MODEL?**

A The results of my DCF analyses are shown on IIEC Exhibit 2, Schedule 2. As shown on Schedule 2, the average DCF cost of common equity for the comparable group is 12.1%.

Q **DO YOU HAVE ANY COMMENTS CONCERNING THE RESULTS OF YOUR DCF ANALYSIS?**

A Yes. My constant growth DCF analysis is, in my judgment, overstated because the current group average five-year IBES projected growth rate is not a reasonable estimate of sustainable growth. The comparable group average IBES five-year growth rate is 6.82%. This growth rate is too high to be sustainable over an indefinite period of time. The growth rate cannot be sustained because it is exceeds the growth rate of the overall U.S. economy. A company cannot grow, indefinitely, at a faster rate than the market in which it sells its products. Based on consensus economic projections, as published by Blue Chip Financial Forecasts, the U.S. economy is estimated to grow at a rate of 5.5%.[2] The U.S. economy growth projection represents a ceiling for a sustainable growth rate for a utility over an indefinite period of time. Therefore, it is reasonable to expect the growth rate for my comparable electric utility group to eventually slow to a growth rate no higher than the growth of the U.S. economy. I discuss appropriate adjustments to my DCF analysis below.

Q DO YOU BELIEVE THE GROWTH RATE FOR ELECTRIC UTILITIES IS CURRENTLY ABNORMALLY HIGH?

A Yes. Electric utilities earnings growth potential over the next five years is abnormally high due to several factors. First, many electric utilities have non-regulated generation affiliates and power trading operations. Wholesale power prices have currently been driven up by a shortage of generating capacity, particularly in the Western and Central markets. This shortage of capacity has driven up wholesale prices, which has had a significantly positive effect on unregulated generating profits. Also, the volatility of wholesale prices has contributed toward the improved earnings for power trading activities. The projected exceptional high profits for unregulated generation affiliates and power trading activities will eventually ease as the shortage of generating capacity in many markets in the U.S. is met by the development of new generation projects. After supply and demand come closer to equilibrium, wholesale power prices should stabilize and non-regulated generation, and power trading affiliates' earnings growth will slow.

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[2] Blue Chip Financial Forecast, August 1, 2001 at 2 (Real GDP: 3.4%, GDP Price Deflator: 2.0%).

Second, many utilities had been involved in mergers and acquisitions (M&A) that have produced reductions to operating expenses. These M&A cost reductions have had a positive impact on utility earnings. However, the improvement to utility earnings will eventually be mitigated as companies get larger and M&A activity slows and/or has a smaller impact on utilities' short-term earnings growth prospects.

Q HAVE YOU USED OTHER MODELS TO CONFIRM YOUR CONSTANT GROWTH ANALYSIS?

A Yes. I have used several models to test the results of my constant growth DCF analysis. These models include a non-constant growth DCF model and a risk premium analysis.

Non-Constant Growth DCF Model

Q WHY SHOULD THE COMMISSION CONSIDER THE RESULTS OF A NON-CONSTANT GROWTH DCF MODEL IN THIS PROCEEDING?

A For the reasons discussed above, the growth rates traditionally used in a constant growth DCF model are not reasonable proxies for a sustainable long-term growth rate. Hence, the constant growth DCF results are biased upwards because of the unusually high growth rate expectations for electric utility securities over the next five years. Since the constant growth DCF model requires a growth rate estimate which is sustainable indefinitely, an analysis must be made to assess the impact on the constant growth model by use of growth rates that are not sustainable. It is important to note that the Commission, and other regulatory commissions, have considered non-constant growth DCF models when the constant growth DCF model results were judged to be either too low or too high. In the early 1990's electric utility growth rates were unreasonably low, therefore, many regulatory commissions did consider the result of a non-constant growth DCF model. Once again, growth rates are unreasonable. Therefore, the Commission should once again consider the non-constant growth model.

Q PLEASE DESCRIBE YOUR NON-CONSTANT GROWTH DCF MODEL.

A In my non-constant growth DCF model, I capture the potential expectation investors believe that electric utility stocks are not currently in a constant growth period (i.e., dividends and earnings will not grow at the same rate, on average, over time). In this model, I assume two growth periods: a short-term growth period which reflected the first five years of the analysis, and a long-term growth period which started in year six and continued indefinitely.

The short-term growth rate was set equal to the comparable group average IBES's projected growth rate. The long-term growth rate was based on Blue Chip Financial Forecasts (August 1, 2001) projected nominal growth to the U.S. economy of 5.5%. The stock price and initial dividend used in this non-constant growth analysis is the comparable electric utility group average used in my constant growth analysis. The parameters of this model are shown on my IIEC Exhibit 2, Schedule 3.

Q WHY DID YOU ASSUME THAT YOUR LONG-TERM STEADY STATE GROWTH RATE WOULD BE ACHIEVED AFTER ONLY FIVE YEARS?

A For several reasons. First, the use of a non-constant growth DCF analysis based on today's market and company financial conditions is problematic. The average dividend payout ratio of the companies included in my comparable group is around 63%. This payout ratio is very near the long-term historical average for the industry, and it is similar to Value Line's projected payout ratio for the industry of around 55% in three to five years.[3]

Second, as discussed above, the five-year growth for my comparable group is abnormally high due to wholesale power markets and M&A activity. Earnings from these factors will slow over time. Value Line projects that wholesale markets will stabilize in the next three to five years. (March 9, 2001, at 155)

Q WHAT ARE THE RESULTS OF YOUR NON-CONSTANT GROWTH DCF ANALYSIS?

A As shown on my IIEC Exhibit 2, Schedule 3, the non-constant growth DCF analysis produces a return of 11.1%.

Risk Premium Model

Q HOW DO YOU INTEND TO USE THE RESULTS OF YOUR RISK PREMIUM ANALYSIS?

A I will use the results of my risk premium analysis as a check on the reasonableness of the results of my discounted cash flow analysis.

Q PLEASE DESCRIBE YOUR BOND YIELD PLUS RISK PREMIUM MODEL.

A This model is based on the principle that investors require a higher ROR to assume greater risk. Common equity investments have greater risk than bonds because bonds have more security of payment in bankruptcy proceedings than common equity and the coupon payments on bonds represent contractual obligations. In contrast, companies are not required to pay dividends on common equity, or to guarantee returns on common equity investments. Therefore, common equity securities are considered to be more risky than bond securities.

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[3] The Value Line Investment Survey, July 6, 2001, at 695.

The risk model is based on the difference between the required return on utility common equity investments and Treasury bonds. The difference between the required return on common equity and Treasury bonds is the risk premium. I estimated the risk premium on an annual basis for each year over the period 1986 through the first quarter of 2000. The common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Treasury bond required returns were based on the prevailing yield of 30-year U.S. Treasury bonds.

Based on this analysis, as shown on my IIEC Exhibit 2, Schedule 4, the average indicated equity risk premium of authorized electric utility common equity returns over U.S. Treasury bond yields has been 4.75%. Of the 15 observations, 11 indicated risk premiums fall in the range of 4.0% to 5.5%. Since the risk premium can vary depending upon market conditions, I believe using an estimated range of risk premiums provides the best method to measure the current return on common equity using this methodology.

Q HOW DID YOU ESTIMATE IP'S COST OF COMMON EQUITY WITH THIS MODEL?

A I added to my estimated equity risk premium a projected 30-year Treasury bond yield. Blue Chip Financial Forecasts projects 30-year Treasury bond yields to be 5.9%, and a 10-year Treasury bond to be 5.6%. Using the 30-year bond yield of 5.9%, and an equity risk premium of 4.0% to 5.5%, produces an estimated common equity return in the range of 9.9% to 11.4%, with a mid-point estimate at 10.7%.

Capital Asset Pricing Model

Q PLEASE DESCRIBE THE CAPM.

A The CAPM method of analysis is based upon the theory that the market required ROR for a security is equal to the risk-free ROR, plus a risk premium associated with the specific security. This relationship between risk and return can be expressed mathematically as follows:

$R_i = R_f + B_i \text{ x } (R_m - R_f)$ where:

R_i = Required ROR for stock i
R_f = Risk-free rate
R_m = Expected return for the market portfolio
B_i = Measure of the risk for stock I

The stock specific risk term in the above equation is beta. Beta represents the investment risk that cannot be diversified away when the security is held in a diversified portfolio. When stocks are held in a diversified portfolio, firm-specific risks can be eliminated by balancing the portfolio with securities that react in opposite direction to firm-specific risk factors (e.g., business cycle, competition, product mix and production limitations).

The risks that cannot be eliminated when held in diversified portfolio are nondiversifiable risks. Nondiversifiable risks are related to the market in general and are referred to as systematic risks. Risks that can be eliminated by diversification are regarded as unsystematic risks. In a broad sense, systematic risks are market risks, and unsystematic risks are business risks. The CAPM theory suggests that the market will not compensate investors for assuming risks that can be diversified away. Therefore, the only risk that investors will be compensated for are systematic or nondiversifiable risks. The beta is a measure of the systematic or nondiversifiable risks.

Q PLEASE DESCRIBE THE INPUTS TO YOUR CAPM.

A The CAPM requires an estimate of the market risk-free rate, the company's beta, and the market risk premium.

Q WHAT DID YOU USE AS AN ESTIMATE OF THE MARKET RISK-FREE RATE?

A I used Blue Chip Financial Forecasts projected Treasury bond yield of 5.9% (August 1, 2001 at 2).

Q WHY DID YOU USE TREASURY BOND YIELDS AS AN ESTIMATE OF THE RISK-FREE RATE?

A Treasury securities are backed by the full faith and credit of the United States government. Therefore, long-term Treasury bonds are considered to have negligible credit risk. Also, long-term Treasury bonds have an investment horizon similar to that of common stock. As a result, investor-anticipated long-run inflation expectations are reflected in both common stock required returns and long-term bond yields. Therefore, the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns.

Treasury bond yields, however, do include risk premiums related to unanticipated future inflation and interest rates. Therefore, a Treasury bond yield is not a risk-free rate. Risk premiums related to unanticipated inflation and interest rates are systematic or market risks. Consequently, for companies with betas less than one, using the Treasury bond yield as a proxy for the risk-free rate in the CAPM analysis can produce an overstated estimate of the CAPM return.

Q WHAT BETA DID YOU USE IN YOUR ANALYSIS?

A I relied on the group average beta estimate for the comparable group. Group average beta is more reliable than a single company beta and will, therefore, produce a more reliable CAPM estimate.

A group average beta has stronger statistical parameters that better describe the systematic risk of the group, than does an individual company beta. For this reason, a group average beta will produce a more reliable return estimate.

As shown on IIEC Exhibit 2, Schedule 5, the group average beta estimate is 0.53.

Q HOW DID YOU DERIVE YOUR MARKET PREMIUM ESTIMATE?

A I derived two market premium estimates, a forward-looking estimate and one based on a long-term historical average.

The forward-looking estimate was derived by estimating the expected return on the market (S&P 500) and subtracting the risk-free rate from this estimate. I estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. The real return on the market represents the achieved return above the rate of inflation.

The Ibbotson and Associates' Stocks, Bonds, Bills and Inflation 2000 Year Book publication estimates the historical arithmetic average real market return over the period 1926-2000 as 9.7%. A current consensus analyst inflation projection, as measured by the Consumer Price Index, is 2.5% through 2002 (Blue Chip Financial Forecasts, August 1, 2001). Using these estimates, the expected market return is 12.4%. The market premium then is the dfference between the 12.4% expected market return, and my 5.9% risk-free rate estimate, or 6.5%.

The historical estimate of the market risk premium was also estimated by Ibbotson and Associates in the Stock, Bonds, Bills and Inflation, 2000 Year Book. Over the period 1926 through 2000, Ibbotson's study estimated that the arithmetic average of the achieved total return on the S&P 500 was 13.0%, and the total return on long-term Treasury bonds was 5.7%. The indicated equity risk premium is 7.3% (13.0% - 5.7% = 7.3%).

Q WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A As shown on IIEC Exhibit 2, Schedule 6, based on the prospective market risk premium estimate of 6.5% and historical estimate of 7.3%, the CAPM estimated return on equity is 9.3% and 9.8%, respectively.

Summary

Q PLEASE SUMMARIZE YOUR FINDINGS.

A The results of my cost of common equity models are summarized in Table 2 below:

TABLE 2

Cost of Equity Summary

Description	Mid-point
DCF Constant Growth	12.1%
DCF Non-Constant Growth	11.1%
Bond Yield Plus Risk Premium	10.7%
CAPM	9.8%

I recommend a return on common equity for IP of 11.1%. From my analyses, as described above, I believe a reasonable range for IP's return on common equity is 10.2% to 12.1%. I recommend a return on equity of 11.1% which is the mid-point of the range. The high end of my range is based on my constant growth DCF results, and the low end of the range is based on the average of my bond yield plus risk premium analysis and CAPM analysis.

Response to Company

Q WHAT RATE OF RETURN ON COMMON EQUITY IS IP REQUESTING IN THIS PROCEEDING?

A IP witness Moul has estimated a return on equity for IP of 12.5%. Mr. Moul bases his return on equity recommendation on a discounted cash flow, risk premium, and CAPM analyses.

Q ARE MR. MOUL'S RETURN ON EQUITY RECOMMENDATION AND SUPPORTING ANALYSES REASONABLE?

A No. Mr. Moul has made adjustments to his DCF, risk premium and CAPM analyses that bias their results and produce an overstated rate of return for IP. Therefore, Mr. Moul's recommended rate of return of 12.5% is unreasonable, and should be rejected.

Q PLEASE DESCRIBE MR. MOUL'S ELECTRIC UTILITY RISK FACTORS DISCUSSION.

A At pages 10 and 11 of Mr. Moul's testimony, he describes four general risk factors for a distribution utility as:

- Competition derived from other fuels, bypassing utility system, the potential secondary market for T&D rights.
- Additional regulatory risk related to the rate setting framework, setting of rates and authorized returns.
- Operational risk related to loss of coordination between utility functional planning, generation and transmission distribution business functions, continued obligation of distribution utility to provide reliable service, continued siting problems, weather events and upgrading and expanding the network.
- Describes the various financial structures related to end users, counter party credit risk, financial penalties related to operations, loss of functional diversification and the claim that utilization of the transmission and distribution network will rest with generators and marketers.

Q DO MR. MOUL'S DISCUSSIONS OF GENERAL RISK FOR DISTRIBUTION COMPANIES JUSTIFY HIS RETURN FOR IP IN THIS PROCEEDING?

A No. As discussed throughout, S&P considers competitive risk for a distribution utility to be limited. The development of a secondary market for T&D services will not increase the operating risk of a distribution utility but rather merely creates economic encouragement for the greater utilization of the distribution system.

Mr. Moul's assessment of regulatory risk is nothing new. Utilities have always faced the risk related to rate design issues, and the rate of return has always been an important issue for utilities in rate proceedings.

Mr. Moul has failed to explain how his operational risk factors are significant for a distribution utility. A distribution utility retains its rights to coordinate and plan the distribution system. The transmission system is expected to be coordinated over a regional transmission organization, which should provide significant planning insight to distribution utilities, such as IP. The other operational risk factors cited by Mr. Moul are not new risk and nor unique to distribution utilities.

Finally, Mr. Moul's discussion of the financial risk structure for transmission and distribution utilities is not persuasive; because he failed to demonstrate that the identified risks are significant. For example, counter part credit risk may lie more with the distribution utility's generation customers than with the utility. The risk assumption will depend on how the distribution utility recovers purchase power cost. Loss of functional diversification may not increase a distribution utilities risk. Conversely, as noted by credit rating agencies sited above, a distribution utility's risk is lower than an integrated utility and a generation only utility. Finally, it remains to be seen whether marketers and generators will control T&D asset utilization. Even if this happens, T&D rates will still be set by regulatory commission to recover a distribution utility's cost of service. Marketers and generators will not control regulatory commission ability to set just and reasonable rates.

Q DOES MR. MOUL CITE SIGNIFICANT RISK FOR DISTRIBUTION UTILITIES THAT ARE PROVIDERS OF LAST RESORT?

A Yes. He observes a distribution utility that must act as provider of last resort assumes risk associated with the procurement of power and recovery of the cost of the same from distribution customers.

Q IS THIS A SIGNIFICANT RISK FOR IP?

A IP's purchased power contracts through the end of 2004 have minimized its commodity risk. In a credit review of IP, Moody's offered the following rating rationale:

> "IP's exposure to supply risk is largely mitigated by two purchased power agreements (PPA) entered into by IP. As a part of IP's electric restructuring plan, the utility transferred its fossil assets to a parent company, Dynegy, Inc., and has signed an intermediate term PPA with its generation affiliate. Dynegy operates the fossil assets. Additionally, IP has signed another intermediate term PPA with Amergen to purchase the output from Clinton." (Moody's Investor Service Opinion Update: Illinois Power Company, March 12, 2001)

IP's commodity risk post-2004 will be a function of the rate mechanisms that are ultimately put in place to assure IP that it will fully recover its cost of power procured for its customers taking service under its provider of last resort tariff. Consequently, while being provider of last resort can potentially expose a distribution utility to commodity risk, this risk can be mitigated by proper rate mechanisms that assure the distribution utility will have the opportunity to recover prudently-incurred purchased power costs procured for the benefit of its customers. In many respects, this commodity risk is similar to the fuel cost recovery risk associated with fuel cost variances through a Fuel Adjustment Clause (FAC). The FAC significantly reduces an integrated utility's commodity risk. While the FAC reduced an integrated utility's fuel commodity risk, it did not eliminate its commodity risk altogether. An integrated utility's commodity risk is for the full generation output, not just fuel. The full generation risk includes: asset concentration, replacement power cost, environmental compliance, and management expertise. Any one of these factors could significantly alter an integrated utility's cost structure in providing generation services. Volatility in cost structure for generation components increases the risk that the integrated utility will not fully recover its generation cost of service through rates.

The important concern here is to ensure that IP's requirement to act as provider of last resort does not unreasonably increase its cost of distribution service. Customers who choose to procure power on their own, rather than through IP, should not bear the cost of higher distribution rates to allow IP an opportunity to recover its cost of acting as supplier of last resort. Hence, any additional cost related to being the supplier of last resort should be covered by customers taking this service from IP. A means of accomplishing this is to construct a tariff post-2004, which minimizes IP's risk of under-recovering its power costs for supplying its customers taking service under the supplier of last resort tariff.

Q HAS MR. MOUL IDENTIFIED SPECIFIC RISKS FACING IP?

A Yes. Mr. Moul alleges that IP's risk profile is strongly influenced by its electricity sold to industrial customers. He notes that industrial customers are generally thought to be higher risk than sales to other classes of customers.

Q IS MR. MOUL CORRECT THAT A DISTRIBUTION UTILITY'S RISK INCREASES BECAUSE OF A HIGH PERCENTAGE OF INDUSTRIAL CUSTOMER SALES?

A No. To the extent distribution rates are primarily demand-related, slowdowns in the economy will not likely significantly reduce an industrial customer's payments to the distribution utility. Demand billing units are much more stable and predictable than energy billing units.

Further, an industrial company's payments to a distribution utility for the large components of its service can be based on facilities contracts. One of the largest investments a distribution utility makes to serve an industrial customer is the substation from which power is taken off the transmission system and delivered to the industrial facility. Often the substations are customer specific. IP has facilities contracts for customer-dedicated facilities. Therefore, its risk for recovering the investment of a customer-dedicated distribution facility is mitigated substantially due to the existence of a facility contract.

Also, for industrial customers the risk of bypass, or self-generation, is not as significant as it is for an integrated electric utility. Even for industrial customers that do self generate, they often must have a reliable source of standby power. Therefore, these customers will likely continue to take service from the distribution utility and a transmission utility to ensure they have access to power in the event their on-site generation is forced out of service, or is down for planned maintenance.

Finally, an industrial facility that self generates would likely want access to the distribution and transmission system to sell excess generated power to the market. In both cases (bypass and self-generation), the distribution and transmission utility would continue to charge for use of their "wires" facilities.

Q AT PAGE 13 OF HIS TESTIMONY, MR. MOUL COMPARES IP'S S&P BUSINESS POSITION RATING TO ELECTRIC UTILITIES IN GENERAL. PLEASE COMMENT.

A Mr. Moul opines that IP's S&P business position rating is 6, on a scale of 1-10 with 1 being the lowest business risk, places it above the Industry average rating of "5". He concludes that IP's above average position risk rating indicates that it should receive a higher rate of return than the industry average.

Mr. Moul's conclusion is baseless. S&P's business risk rating is used in conjunction with both its quantitative financial analysis, and its qualitative evaluation of a Company to gage "total" risk, that is both business risk and financial risk, which is what credit ratings are based on. Mr. Moul's conclusion that IP should receive an above average rate of return is based only on the business position rating, and not, as S&P does, an evaluation of IP's total risk in comparison to the industry. Consequently, his support for his conclusion that IP should receive an above average rate of return is not based on a complete and credible analysis.

Further, it isn't clear if IP's current business position ranking of 6 is a continuation of its ranking as an integrated electric utility, or has been updated since it has transformed itself into only a transmission and distribution or wires utility. Hence, since this is a relatively new development, IP should show a complete S&P report summarizing its current business assessment, and justification for its existing business risk position.

Q PLEASE DISCUSS MR. MOUL'S FUNDAMENTAL RISK ANALYSIS IN SELECTING HIS COMPARABLE GROUP.

A Mr. Moul conducts a fundamental risk analysis of his Alliance RTO (RTO) group, Gas Distribution Group (GDG), the S&P electric utility index, and IP. He first compared IP's bond rating to the of the comparison group average. Second, he constructed financial ratios from data over the period 1995 through 1999 to draw comparisons between IP and the proxy groups. Mr. Moul, during this time period, considered financial ratios such as certain market ratios, common equity ratio, return on book equity, operating ratios, coverages of fixed obligations, quality of earnings, internally generated funds and betas. Based on this analysis, he concluded that the risk of IP is somewhat higher than that of the RTO group and the GDG's ratios are somewhat lower for IP but their betas show higher systemic risk. (Id. at 22-23)

Q PLEASE DESCRIBE MR. MOUL'S COMPARISON OF IP'S BOND RATING TO THAT OF HIS COMPARISON GROUPS.

A The S&P and Moody's bond rating Mr. Moul identified for IP and his comparison groups are listed below in Table 3. As shown in Table 3, IP's bond ratings are reasonably comparable to the RTO group and S&P electric group. IP's bond rating is one rating notch lower than each group's average rating. The GDG group's bond rating is not as comparable to IP's as are the other two groups.

TABLE 3

Bond Rating Comparison

	S&P	Moody's
Alliance RTO	A-	A3
Gas Distribution Companies	A+	A1
S&P Electrics	A-	A2
Illinois Power Company	BBB+	Baa

Using a bond rating as a factor to select companies to include in a comparable group is reasonable, however, by itself a bond rating is not sufficient data to conclude that IP's common equity is more risky than the comparable groups.

Q ARE MR. MOUL'S FINANCIAL RATIOS COMPARISONS A REASONABLE METHOD OF ESTIMATING COMPARABLE GROUPS FOR IP?

A No. His study period, which covers the period 1995 through 1999, predominantly captures ratios of P when it was an integrated electric utility, and more importantly, when it continued to own and operate the Clinton Power Station. During this time period, IP's bond rating, financial ratios and market valuation ratios were all strongly influenced by the poor operation of the Clinton Power Station. For example, Clinton was forced out of service for an extended period during this study period starting in September 1996. This outage caused an erosion to IP's financial results and ratios during this time period. Consider that in a November 1998 utility credit report, S&P stated the following concerning the impact of the Clinton outage on IP's financial measures:

> "Clinton has been inoperable since September 1996, causing erosion in Illinois Power's key financial measures. Since 1996, the utility's cash flow coverage has fallen to 3.6 times (x) from 4.7x, funds from operations to debt to 16% from 23%, and internal funding to about 79% from more than 200%. As a result of various write-downs, debt leverage has risen to 58% from 52%. However, the Company's problems should dissipate once Clinton returns to service and its future is decided. PECO Nuclear, a Division of PECO Energy Co., and a superior nuclear operator, is managing the plant. A year-end 1998/early 1999 restart is targeted." (Global Utilities Rating Service, Utility Credit Report, Illinois Power Company, Standard & Poor's November 1998)

Consequently, Mr. Moul's financial ratio analysis does not model the current distribution utility risk of IP. Rather, it reflects a financially distressed integrated utility that owns a poorly run nuclear station. Therefore, justification for his conclusion that the RTO and GDG are good proxy groups to measure IP's return on equity is based on these ratios is severely flawed.

Q PLEASE DESCRIBE MR. MOUL'S DISCOUNTED CASH FLOW ANALYSIS.

A Mr. Moul performed a DCF analysis on the RTO group and GDG. The parameters of his DCF analysis are shown on his IP Exhibit 4.11, Schedules 6, 7 and 8. Mr. Moul uses forecasted growth rates to derive the growth rate component, a three-month average dividend yield, and an adjustment to the traditional DCF model to produce a DCF for his RTO and GDG of 13.73% and 12.31%, respectively (IP Ex. 4.1, at 38).

Q IS MR. MOUL'S DCF ANALYSIS REASONABLE?

A No. Mr. Moul's analysis produces overstated results for the following reasons:

1. His growth rates used for his RTO group and GDG of 7.5% and 6.25%, respectively, overstate a reasonable estimate of a sustainable growth rate for these utility companies. Since the growth rate is unsustainably high, the DCF return is overstated. Mr. Moul should have tested the results of his constant DCF analysis with a non-constant growth DCF model. Had he done that as I

did, as described above, Mr. Moul would have found that his constant growth DCF estimate is overstated.

2. Mr. Moul's growth rate estimate for his RTO group of 7.5% is unreasonable because it overstates the consensus growth rate published by IBES and Zack's for this utility group. Using his own data, the consensus of analysts' forecasted growth for these companies over the next five years is 6.75% and 6.91%, respectively. Using the consensus analysts' growth rates as published by IBES would lower his DCF return for the RTO group from 12.27% to 11.49%. Although the growth rate is still unsustainable, the adjusted DCF return is too high.

3. Mr. Moul's proposal to adjust the results of his DCF analysis for either the utility's market to book ratio, or to perform a leverage adjustment is inappropriate and should be rejected. Mr. Moul's proposed adjustment for these two factors inappropriately increases his RTO group and GDG DCF returns by 1.46% and 0.63%, respectively (IP Ex. 4.1, at 38).

Q PLEASE EXPLAIN WHY MR. MOUL SHOULD HAVE USED A NON-CONSTANT GROWTH MODEL TO TEST THE REASONABLENESS OF HIS CONSTANT GROWTH DCF MODEL?

A The fact that Mr. Moul's growth rates are unreasonably high is evidenced by several factors. First, his growth rates are higher than the expected nominal growth to the U.S. economy. A consensus analyst projection of the nominal growth to the U.S. economy through 2002 is 5.5%. These companies' growth rates cannot exceed the growth of the U.S. economy indefinitely, because they cannot indefinitely grow faster than the economy into which they sell their goods and services. This unsustainable growth rate expectation is simply not rational.

Second, the fact that these companies' growth rates for the next five years does not reflect a sustainable growth rate is further evidenced from the information in Mr. Moul's own schedules. Specifically, as shown on his Schedule 8, using Value Line projections, earnings are projected to grow at a significantly higher growth rate than dividends over the next three to five-year period. For the RTO group, Value Line's projections indicate an earnings growth of 8.3% and dividend growth rate of 1.83%. Earnings growth rates are used as a proxy for dividend growth rates in a constant growth DCF model. The constant growth model requires the assumption that earnings and dividends will grow at approximately the same rate over an indefinite rate of time. During periods where earnings growths are significantly higher than dividend growth, it is clearly evident that the sustainable growth rate assumption is not valid.

With earnings growth rates substantially higher than dividend growth rates, the utility's payout ratio will decline, which will temporarily fund an earnings growth that is higher than that which will be achieved sustainably over an indefinite period. As the payout ratio stabilizes, a reasonably constant percentage of earnings would be paid out as dividends, then earnings growth will slow and dividend growth will increase to a more normal sustainable level. Hence, over the next five years, the constant growth rate assumption does not hold for these companies. The same relationship holds for the GDG, where the Value Line earnings growth projection is 8.6%, and its dividend growth projection is 3.1% (IP Ex. 4.1, Schedule 8, at 2).

Finally, in order for the RTO group and GDG to sustain steady growth rates of 7.5% and 6.25%, respectively, the companies would have to achieve a long-term earned return on book equity of 34% and 25%. The steady state growth rate is a function of the earnings retention ratio (or 1- percentage of earnings paid out as dividends) and the return on book equity. The dividend payout ratios for the groups are shown on Mr. Moul's IP Exhibit No. 4.11, pages 6 and 8, Schedule 4. Based on Mr. Moul's recommendation for IP of 12.5%, and the RTO group and GDG actual book equity returns on average of 12.7% and 11.7%, the indicated growth rates could not be sustained. Hence, the 5-year growth rates overstate a sustainable growth rate needed for the constant growth DCF model.

Q SHOULD MR. MOUL HAVE USED THE CONSENSUS ANALYSIS EARNINGS GROWTH RATE ESTIMATE IN HIS DCF ANALYSIS?

A Yes. As discussed above, consensus analysts' growth rate estimates are the best proxies for investor expectations. It is unclear whether any individual analysis growth projection is more representative of the general market expectations. A consensus of the analysts' growth rates is likely to account for all relevant diversity in the individual analyses, but also produce rates that are considered to be appropriate. Therefore, using a consensus of the analysts' growth rate projections is a better proxy for overall market expectations than is an individual analyst projection.

Q IS MR. MOUL'S PROPOSED ADJUSTMENT TO HIS DCF RESULT FOR A MARKET TO BOOK RATIO OR A LEVERAGE ADJUSTMENT INAPPROPRIATE?

A Mr. Moul's adjustment to a DCF result based on the market to book ratio will provide the utility an incentive to "gold plate" utility plant investments.

Q PLEASE EXPLAIN.

A If the DCF return is increased by the market to book ratio adjustment, then the utility will be provided an opportunity to earn a higher rate of return on incremental utility plant investments than it could earn by making other comparable risk investments, such as repurchasing its own stock. As an example, is Mr. Moul's data where an

RTO utility earns a DCF return of 13.73% by making incremental investments in utility plant. Alternatively, it could earn a 12.27% return by investing in its own stock (the DCF return without the leverage adjustment). Mr. Moul's adjustment to the DCF results will provide the utility an economic incentive to gold plate utility plant investments, because it will have an opportunity to realize an inordinately high risk adjusted return on these incremental investments. It is not to the advantage of customers to provide the utility an undue economic incentive to make excessive utility plant investments. Therefore, Mr. Moul's proposed adjustment should be rejected.

Mr. Moul's proposal to adjust the DCF results for a leverage differential between his comparable groups and IP is also flawed. Mr. Moul himself recognizes that total investment risk is a function of both financial and business risk. (IP Ex. 4.4, at 1). Mr. Moul's proposed leverage is based on the assumption that only financial risk differentials affect an investors required return. Mr. Moul's own evidence contradicts this flawed assumption. Alternatively, Mr. Moul has provided no evidence that the business risk is comparable between IP, the RTO group and the GDG, and therefore the only adjustment that need be made is for financial risk differences. Indeed, his fundamental risk analysis is flawed because it is based on IP when it was an integrated electric utility, which owned a nuclear generating station. IP's current risk as a wires-only utility is substantially different than IP's business risk was as an integrated electric utility. Therefore, his proposed leverage adjustment should be rejected.

Q HAS THE COMMISSION PREVIOUSLY CONSIDERED A LEVERAGE ADJUSTMENT TO A DCF MODEL BASED ON THE MILLER MODEL, AS PROPOSED IN THIS PROCEEDING BY MR. MOUL?

A Yes. In a recent Illinois-American Water Company rate case, Docket No. 00-0340, Mr. Moul testified in support of leverage adjustments to the DCF and CAPM models. He offered much of the same argument in that proceeding as he does here. In particular, he proposed the use of a leverage adjustment. The Commission did not accept Mr. Moul's recommended leverage adjustment in that proceeding.

In IP's last delivery service tariff case, Docket Nos. 99-0120/99-0134, the Commission specifically rejected the use of the Hamada model, which is similar to the Miller model, in estimating the utility's cost of capital for ratemaking purposes: ". . .that while the Hamada equation may be useful for measuring the relative cost of capital over a range of capital structures, it may not be appropriate for estimating a specific cost of capital for ratemaking purposes. This was true in ComEd's securitization case, IP's securitization case and it is true in the current proceeding." (Order at 55) The Commission went on to accept Staff's recommendation and reject IP's.

In addition, in several rate cases in the early 1990's involving both Commonwealth Edison Company and IP, these utilities relied upon the Miller model to argue that the utility's return on equity should be increased to adequately compensate investors. (Illinois Power Company, Docket No. 91-0147, Order at 158-165, (Aug. 7, 1992); Commonwealth Edison Company, Docket No. 87-0427 on Remand, Order at 101 (Jan. 9, 1995); Commonwealth Edison Company, Docket No. 94-0065, Order at 199-201 (Jan. 9, 1995)). In each case, the Commission was not persuaded to make the requested adjustment, finding that the use of the Miller model for estimating the utilities' required return on common equity or the analysis incorporating the Miller Model was inappropriate.

Q PLEASE DESCRIBE MR. MOUL'S RISK PREMIUM ANALYSIS.

A Mr. Moul's equity risk premium analysis is based on the theory that an equity return is equal to the interest rate on the companies' corporate bond rate, plus an equity risk premium. He estimates the equity risk premium by a comparison of the achieved return between the S&P composite index and corporate bonds, and the S&P public utility index to public utility bonds (IP Ex. 4.11, Schedule 10, at 1). Based on this comparison, he attempts to reflect fundamental risk differences between the S&P public utility indices and his RTO group and GDG. Based on this analysis, he estimates a risk premium for IP of 5.5% (IP Ex. 4.1, at 44). He then projects a return on an "A" public utility bond of 7.5% to produce an equity risk premium return on equity estimate of 13.0%.

Q IS MR. MOUL'S RISK PREMIUM ANALYSIS REASONABLE?

A No. His risk premium estimate of 5.5% over public utility bond yields is excessive. This is evidenced by a review of commission-authorized equity risk premiums in relationship to contemporary utility bond yields achieved over the last ten years. Regulatory commissions set authorized returns on equity for utility companies based on expert witness recommendations of the contemporaneous investor-required returns during the course of a rate proceeding. Therefore, the authorized return on common equity for utilities reflects the commission's independent assessment of the investor-required returns for those utilities during the relevant time periods.

As shown on my IIEC Exhibit 2, Schedule 7, the average equity risk premiums authorized by regulatory commissions over the last ten years has been 3.47%. Using this equity risk premium in relationship to Mr. Moul's projected 7.5% "A" public utility bond yield produces a return on common equity of 10.97%.

Q PLEASE DESCRIBE MR. MOUL'S CAPM ANALYSIS.

A Mr. Moul's CAPM analysis is based on an estimate of RTO groups and GDG beta, an estimate of the risk free rate, and market risk premium. Mr. Moul estimates an appropriate beta for the RTO group and GDG by taking the Value Line betas for each of these groups of .57 and .60, respectively, and then adjusting them for the difference between book value and market value. His adjustment is to increase the RTO group and GDG beta up to 0.75 and .70 for the RTO group and GDG, respectively. He uses a projected year Treasury bond as the risk free rate of 5.25%. He then estimates a market risk premium of 10.78%, which is the average of two estimates. First, he observes that the historical achieved return of the S&P 500, and a market proxy relative to the achieved return on Treasury bonds over the period 1929 through 2000 has been 7.3%. He also uses value line data to project the expected three to five year return for the Value Line composite index of 19.15% (IP Ex. 4.9, at 4). He then subtracts from this Index return his estimate of the risk free rate, 5.25%, to produced a market risk premium of 14.26%. His market return estimate is the average of 14.2% and 7.3%, or 10.78%.

Q IS MR. MOUL'S CAPM ANALYSIS REASONABLE?

A No. His CAPM return should be rejected for several reasons. First, his proposed adjustment to the Value Line betas is inappropriate and should be rejected. A Value Line beta attempts to capture all of the systematic risks of the composite utility groups, and no adjustment need be made for the differences between market to book ratio. Mr. Moul has wrongly singled out financial risk, while ignoring all the other risk factors that comprise systematic risk. Second, his projected return on the Value Line composite index of 19.51% does not produce a reasonable sustainable return on the market and, therefore, the indicated market risk premium is unreasonable. As evidenced by the historical achieved return on the market of 7.3%, the expected market risk premium over the next three to five years of 14.26% is simply unreasonably. His projected return is significantly greater than the anticipated growth rate of the U.S. economy, which demonstrates the unsuitability of the analysis.

Using the historical achieved return premium on the market of 7.3%, and the true Value Line betas, would produce an RTO group and GDG CAPM return of 9.4% and 9.6%, respectively. Hence, for these reasons, Mr. Moul's conclusion that the CAPM return for these two groups of 13.34% and 12.8% is unreasonable and should be rejected.

Q DOES MR. MOUL PROPOSE A SIZE ADJUSTMENT TO THE CAPM RESULTS?

A Yes. He bases his size of the firms' adjustments on the difference in the achieved returns as measured by the Ibbotson & Associates Stocks, Bonds, Bills and Inflation. He recommends that the CAPM returns be increased by 1.07% for the GDG. He apparently makes no such adjustment for the RTO group.

Q IS HIS SIZE ADJUSTMENT REASONABLE?

A No. Gas distribution companies, and in particular, IP, do not go to the equity markets by themselves. Rather, they receive equity capital from their parent companies. Further, these companies benefit from parent company access to equity capital and administrative and general support that are not available to a stand-alone small company. Hence, even if these companies are smaller than the composite group, they are not reflective of the small companies included in the Ibbotson study, which is the basis for Mr. Moul's adjustment. The small companies included in the Ibbotson study are stand-alone, market traded, small capitalization companies. These companies have no resemblance and are not reasonable risk proxies for IP, the RTO group, or the GDG. Therefore, Mr. Moul's proposed size adjustment is unreasonable and should be rejected.

Q DOES MR. MOUL PROPOSE A COMPARABLE EARNINGS ANALYSIS AS SUPPORT FOR HIS RETURN ON COMMON EQUITY FOR IP?

A No, not really. However, he does include a comparable earnings analysis, but only as alleged confirmation as to his recommendations. Nevertheless, a comparable earnings analysis is an inappropriate and inexact method for estimating a return for a public utility. A comparable earnings analysis measures the accounting return, and not the investor required return. Public utilities' authorized returns on common equity should be based on the investor-required return.

The investor required return is the return that investors demand to receive in order to make an investment. If the authorized return is set equal to the investor-required return, utilities will have the incentive to make and will receive fair compensation for incremental plant investment. The accounting return does not measure a fair compensation return.

Since the accounting return can be higher or lower than the investor required return, the Commission can have no confidence that the comparable earnings return produces a reasonable estimate of what returns investors are requiring in order to make an investment today. These returns should only be measured by market-based models, such as the DCF and CAPM analyses.

Q WHAT HAS BEEN THE COMMISSION'S PRACTICE IN TERMS OF WHAT MODELS IT RELIES ON IN DECIDING ROE FOR UTILITIES?

A The Commission, as well as most other jurisdictions, relies on market-based models such as the DCF, risk premium, and CAPM models to estimate investor-required returns. The Commission authorized returns on equity are then based on reasonable estimates of the investor required return. I am not aware of any regulatory commission in the last ten years giving any weight to a comparable earnings analysis in developing the authorized return on common equity.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes.

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Qualifications of Michael Gorman

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Michael P. Gorman. My business mailing address is P. O. Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q PLEASE STATE YOUR OCCUPATION.

A I am a consultant in the field of public utility regulation with Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A In 1983 I received a Bachelors of Science Degree in Electrical Engineering from Southern Illinois University, and in 1986, I received a Masters Degree in Business Administration with a concentration in Finance from the University of Illinois at Springfield. I have also completed several graduate level economics courses.

In August of 1983, I accepted an analyst position with the Illinois Commerce Commission (ICC). In this position, I performed a variety of analyses for both formal and informal investigations before the ICC, including: marginal cost of energy, central dispatch, avoided cost of energy, annual system production costs, and working capital. In October of 1986, I was promoted to the position of Senior Analyst. In this position, I assumed the additional responsibilities of technical leader on projects, and my areas of responsibility were expanded to include utility financial modeling and financial analyses.

In 1987, I was promoted to Director of the Financial Analysis Department. In this position, I was responsible for all financial analyses conducted by the staff. Among other things, I conducted analyses and sponsored testimony before the ICC on rate of return, financial integrity, financial modeling and related issues. I also supervised the development of all Staff analyses and testimony on these same issues. In addition, I supervised the Staff's review and recommendations to the Commission concerning utility plans to issue debt and equity securities.

In August of 1989, I accepted a position with Merrill-Lynch as a financial consultant. After receiving all required securities licenses, I worked with individual investors and small businesses in evaluating and selecting investments suitable to their requirements.

In September of 1990, I accepted a position with Drazen-Brubaker & Associates, Inc. In April 1995 the firm of Brubaker & Associates, Inc. (BAI) was formed. It includes most of the former DBA principals and Staff. Since 1990, I have performed various analyses and sponsored testimony on cost of capital, cost/benefits of utility mergers and acquisitions, utility reorganizations, level of operating expenses and rate base, cost of service studies, and analyses relating industrial jobs and economic development. I also participated in a study used to revise the financial policy for the municipal utility in Kansas City, Kansas.

At BAI, I also have extensive experience working with large energy users to distribute and critically evaluate responses to requests for proposals (RFPs) for electric, steam, and gas energy supply from competitive energy suppliers. These analyses include the evaluation of gas supply and delivery charges, cogeneration and/or combined cycle unit feasibility studies, and the evaluation of third-party asset/supply management agreements. I have also analyzed commodity pricing indices and forward pricing methods for third party supply agreements. Continuing, I have also conducted regional electric market price forecasts.

In addition to our main office in St. Louis, the firm also has branch offices in Kerrville, Texas; Plano, Texas; Denver, Colorado; and Chicago, Illinois.

Q HAVE YOU EVER TESTIFIED BEFORE A REGULATORY BODY?

A Yes. I have sponsored testimony on cost of capital, revenue requirements, cost of service and other issues before the regulatory commissions in Arizona, Delaware, Georgia, Illinois, Indiana, Michigan, Missouri, New Mexico, Oklahoma, Tennessee, Texas, Utah, Vermont, West Virginia, Wisconsin and Wyoming. I have also sponsored testimony before the Board of Public Utilities in Kansas City, Kansas; presented rate setting position reports to the regulatory board of the municipal utility in Austin, Texas, and Salt River Project, Arizona, on behalf of industrial customers; and negotiated rate disputes for industrial customers of the Municipal Electric Authority of Georgia in the LaGrange, Georgia district.

Q PLEASE DESCRIBE ANY PROFESSIONAL REGISTRATIONS OR ORGANIZATIONS TO WHICH YOU BELONG.

A I earned the designation of Chartered Financial Analyst (CFA) from the Association for Investment Management and Research (AIMR). The CFA charter was awarded after successfully completing three examinations which covered the subject areas of financial accounting, economics, fixed income and equity valuation and professional and ethical conduct. I am a member of AIMR's Financial Analyst Society.